UNITED STATES DISTRICT COURT
WESTERN DISTRICT OF OKLAHOMA

UNITED STATES OF AMERICA,

Plaintiff,

v.

OKLAHOMA GAS & ELECTRIC CO.,

Defendant.

Civil Action No. 5:13-cv-00690-D

PLAINTIFF UNITED STATES' OPENING BRIEF IN SUPPORT OF ITS MOTION FOR SUMMARY JUDEMENT AND DECLARATORY RELIEF

EXHIBIT 3-G

OGE Energy Corp. PO Box 321
Oklahoma City, Oklahoma 73101-0321
405-553-3000
www.oge.com

Company File

OG/E

January 26, 2006

CERTIFIED MAIL 7004 0750 0000 9145 9063

Mr. Eddie Terrill, Division Director
Air Quality Division
Oklahoma Department of Environmental Quality
P.O. Box 1677
Oklahoma City, Oklahoma 73101-1677

RE: Oklahoma Gas & Electric Co. Sooner Generating Station Unit 1 Economizer, Steam Turbine Project and Boiler Surface Optimization

Dear Mr. Terrill:

Enclosed is a document titled "Air Quality Regulatory Applicability for Proposed Economizer Replacement, Steam Turbine Project and Boiler Reheat Surface Optimization". The document identifies the applicable regulatory citations and discusses the methodology that was used to determine past actual and future projected actual emissions.

The Sooner project will begin on January 30, 2006. It is anticipated that the project will be completed and the unit restarted on April 3, 2006. Therefore, post-project emissions will be calculated from January 2007 through December 2007 and reported to ODEQ within 60 days after the end of 2007.

If you have any questions, please contact Laura Herron at 553-3057 or me at 553-3690.

Sincerely,

David Branecky

David Branecky
Manager Air Quality

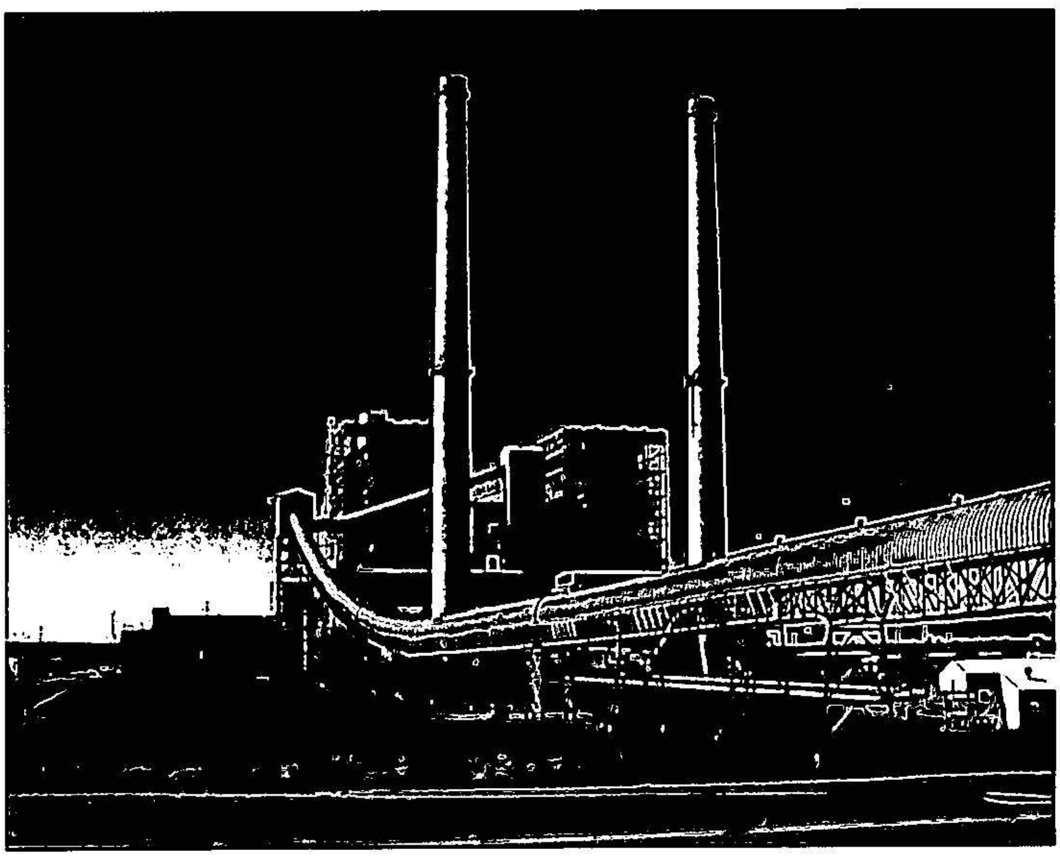
Enclosure:

Cc: IXOS id 2918 John Parham
Ford Benham

RECEIVED
JAN 27 2006
AIR QUALITY

AIR QUALITY REGULATORY APPLICABILITY
FOR
PROPOSED ECONOMIZER REPLACEMENT, STEAM TURBINE PROJECT, AND BOILER REHEAT SURFACE OPTIMIZATION

OKLAHOMA GAS & ELECTRIC SOONER GENERATING STATION UNIT 1



January 26, 2006

SUMMARY

In order continue to provide a reliable source of electricity to our customers Oklahoma Gas & Electric Company (OG&E) finds it necessary to replace the economizer, replace turbine HP/IP rotor and LP blades, and optimize the reheat section of the Boiler (Project) on Sooner Generating Station Unit 1. This document determines potential emission impacts for the proposed project, the potential applicability to New Source Performance Standards (NSPS) and New Source Review (NSR), and sets forth OG&E's proposed plan of action for compliance. This project will begin on January 30, 2006 and is scheduled to be completed by April 3, 2006.

BACKGROUND & PROJECT DESCRIPTION

Sooner Power Plant consists of two separate coal-fired units (#1 and #2). Each of the coal units is nominally rated at approximately 570 MW generating capacity and has been in operation for approximately 25 to 30 years. Oklahoma Department of Environmental Quality (ODEQ) has issued a Title V operating permit for the facility as Permit # 96-284-TV. The unit under consideration has permit emission limits in terms of pounds of specific pollutant per million Btu. The Sooner Power Plant is located in Noble county, which is considered "in attainment" of the Federal air quality standards.

The Sooner Unit 1 economizer project will involve the replacement of the economizer tubes. An "economizer" in a power boiler improves boiler efficiency by extracting heat from the boiler exhaust gas stream. In the economizer, heat is transferred to preheat the feedwater to the boiler. Replacement of the economizer is necessary due to the failures of the serpentine hanger support system and other tube failures. The tubes replaced will have approximately the same effective heating surface area and heat transfer capability, but they will have an improved tube support system and be arranged in a different layout.

The Sooner Unit 1 General Electric steam turbine consists of a High Pressure (HP) section, an Intermediate Pressure (IP) section, and two double-flow Low Pressure (LP) sections. The turbine project will include replacement of the HP/IP rotor and replacement of the last row of LP turbine blades. The HP/IP rotor replacement provides an advanced design steam path intended to improve heat rate (efficiency) and power output. The LP blading replacement will also improve heat rate and power output due to improved design, but is also needed due to normal deterioration of the existing blades. Approximately 30 MW power improvement is predicted with the same initial steam conditions.

The Sooner Unit 1 boiler will have additional heat transfer surface added to the reheat section. The new advanced design steam path turbine extracts more energy from the high pressure steam than the original turbine, leaving less energy in the cold reheat. In order to maintain 1000 F final steam temperature to the IP turbine section, the additional heat transfer surface is necessary to absorb more heat.

SUPPORTING DATA

- The project is scheduled for a unit overhaul during the period from January 30 to around April 3, 2006.
- The cost of the economizer replacement is approximately $4,759,000.
- The cost of the turbine project is approximately $8,712,000.
- The cost of the boiler reheat optimization project is approximately $2,564,000.
- The original cost of construction of Unit 1 excluding siding, foundation, roof, and all other attachments was approximately $45,251,816.00 (1978 dollars).
- The purpose of this project is to minimize downtime, reduce potential safety hazards, and increase efficiency.
- Emission factors for Sooner Unit 1 (pulverized coal, dry bottom, tangentially fired boiler) are as follows:
  - CO = 0.5 lb/ton based on AP-42 Table 1.1-3 (9/98)
  - VOC = 0.06 lb/ton based on AP-42 Table 1.1-19 (9/98)
  - TSP = 0.032 lb/mmBtu per compliance test
  - PM_{10} = 0.02144 lb/mmBtu based on 67% of TSP per AP-42 table 1.1-6 (9/98)
  - NO_x actual emissions from Acid Rain CEMS
  - SO_2 actual emissions from Acid Rain CEMS
  - H_2SO_4 emissions based on SO_2 emissions and factors from Southern Company
  - Average heat content of coal = 8,771 Btu/lb

APPLICABLE AIR QUALITY REGULATIONS

New Source Performance Standards

The coal-fired unit in question is currently applicable to NSPS Subpart D. There is a possibility that the changes under consideration could be considered a "modification" [1] or "reconstruction" [2] and thus make the units applicable to Subpart Da.

"Modification" excludes "an increase in production rate of an existing facility, if that increase can be accomplished without a capital expenditure on the facility." A "capital expenditure" level is established in IRS Publication 534 (last listed in the 1984 edition) for each type of industry. The electric power generation industry is listed with a capital expenditure threshold of five percent. This has been interpreted to require the comparison of the capital cost of construction of the emissions unit (at time of construction) as compared with the cost of changes under consideration (present dollars). In this case the changes planned for Sooner Unit 1 boiler are estimated to cost a total of approximately $7,323,000. The past actual cost of construction of the Number 1 Unit was approximately $45,251,816.00 (1978 dollars). Thus, the proposed changes cost approximately 16.2 percent of the original cost. However, to be considered a modification, there must be an accompanying increase in the emission rate. The economizer replacement and the boiler reheat surface optimization do not result in increased heat input and thus do not result

[1] 40 CFR Part 60, paragraph 60.14
[2] 40 CFR Part 60, paragraph 60.15

in an increase in the hourly emission rate. Therefore, even though the project qualifies financially as a modification; because the hourly emissions do not increase the unit will not be subject to Subpart Da.

"Reconstruction" under NSPS definitions includes changes whose "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility." The costs of the changes under consideration are relatively minor compared to the cost of a new facility and thus the changes would not be considered a reconstruction under NSPS.

New Source Review

Whether or not physical changes to equipment at existing power plants trigger New Source Review (NSR) permitting requirements can be a complicated and controversial issue. The Prevention of Significant Deterioration (PSD) program is the NSR permitting mechanism for projects that occur in areas that are in attainment of the National Ambient Air Quality Standards (NAAQS). Traditionally, assessing PSD applicability for a physical change to an existing emission unit at a power plant is a two-step process. First, emission increases from the proposed project are determined on a pollutant-by-pollutant basis and compared to the relevant Significant Emission Rates (SER). If the emission increase after the first step does not exceed the applicable SER, the project does not trigger PSD permitting requirements for that pollutant. For individual pollutants that do exceed the relevant SER, the second step requires a netting analysis. A netting analysis involves a determination of creditable contemporaneous period. With respect to "electric utility steam generating units," the Wisconsin Electric Power Company (WEPCO) series of court opinions, regulations, and guidance documents establish a framework within which a regulated party can calculate emission increases by which *past actual* emissions are subtracted from expected *future actual* emissions.

EMISSION CALCULATION METHODOLOGY

Baseline actual emissions for Sooner Unit 1 were determined as defined by 40 CFR 52.21(b)(48) which says, "Baseline actual emissions means the rate of emissions, in tons per year, of a regulated NSR pollutant, as determined in accordance with paragraphs (b)(48)(i) through (iv) of this section". In addition, 40 CFR 52.21 (b)(48)(i) says, "For any existing electric utility steam generating unit, baseline actual emissions means the average rate in tons per year, at which the unit actually emitted the pollutant during any consecutive 24-month period selected by the owner or operator within the 5-year period immediately preceding when the owner or operator begins actual construction for the project…".

Projected actual emissions for Sooner Unit 1 were determined as defined by 40 CFR 52.21(b)(41)(i) which says, "Projected actual emissions means the maximum annual rate, in tons per year, at which an existing emissions unit is projected to emit a regulated NSR pollutant in any one of the 5 years (12-month period) following the date the unit resumes regular operation after the project,…". 40 CFR 52.21(b)(41)(ii)(c) says that in determining projected actual

emissions under paragraph (b)(41)(i), the owner or operator of the major stationary source, "Shall exclude, in calculating any increase in emissions that results from the particular project, that portion of the unit's emissions following the project that an existing unit could have accommodated during the consecutive 24-month period used to establish the baseline actual emissions under paragraph (b)(48) of this section and that are also unrelated to the particular project, including any increased utilization due to product demand growth."

For Sooner Unit 1, 40 CFR 52.21(r)(6)(iii) and (iv) will be followed to demonstrate future actual emissions. 40CFR 52.21(r)(6)(iii) says, "The owner or operator shall monitor the emissions of any regulated NSR pollutant that could increase as a result of the project and that is emitted by any emissions unit identified in paragraph (r)(6)(i)(b) of this section; and calculate and maintain a record of the annual emissions, in tons per year on a calendar year basis, for a period of 5 years following resumption of regular operations after the change, or for a period of 10 years following resumption of regular operations after the change if the project increases the design capacity of or potential to emit that regulated NSR pollutant at such emissions unit." 40 CFR 52.21(r)(6)(iv) says, "If the unit is an existing electric utility steam generation unit, the owner or operator shall submit a report to the Administrator within 60 days after the end of each year during which records must be generated under paragraph (r)(6)(iii) of this section setting out the unit's annual emissions during the calendar year that preceded submission of the report."

Therefore, if Sooner Unit 1 resumes regular operating as scheduled during April 2006, emissions will be calculated from January 2007 through December 2007 and reported to ODEQ within 60 days after the end of 2007. The final emissions report for this project will be due 60 days after the end of 2011.

EPA Region 5 has further clarified the WEPCO decision by a letter (Appendix A) concerning the Detroit Edison Company dated May 23, 2000. Detroit Edison planned to conduct a turbine components replacement. EPA concluded that the replacement could not be considered routine but could be exempt from PSD consideration as long as there was not a significant increase of emissions. The letter also reaffirms the exclusion from consideration of emission increases "...which could have been accommodated before the change and is unrelated to the change, such as demand growth."

To verify that a significant increase of emissions would not occur, the EPA letter required Detroit Edison to provide project information to the local regulatory agency (Michigan DEQ) as listed below.

1. Calculation of past actual to future actual emissions comparison.
2. Annual reports for at least five years demonstrating that the renovation did not result in a significant emission increase (40 CFR 52.21(21)(v)).

EMISSIONS IMPACT OF THE PROJECT

Past actual emissions for Sooner Unit 1 for the previous 5 years have been collected through the Acid Rain Continuous Emissions Monitoring System (CEMS) and emissions calculations. This

data is summarized in Appendix B. The data was reviewed to find the 24-month rolling period with the highest activity/emission rates. This period of time was determined separately for each measure of activity: heat input, stack flow, SO_2 emissions and NO_x emissions. The highest activity rate for heat input derived emissions was determined to be during the 24-month block ending at the end of March 2004. Table 4-1 shows the allowable increase in emissions that would not be subject to PSD requirements. This analysis is based on the "past actual to future actual" test. If the proposed project increases emissions more than the allowable limit, excluding increases due to system generation demand growth, then the unit would be subject to PSD for that specific pollutant.

TABLE 4-1. ALLOWABLE EMISSIONS FOR PROJECT

Pollutant	Past Actual (tpy)	SER (tpy)	Projected Future Actual (tpy)
PM_{10}	448.14	15	463.04
SO_2	10,453.00	40	10,492.90
NO_x	8,023.89	40	8,063.79
VOC	71.49	40	111.39
CO	595.78	100	695.68
H_2SO_4	4.01	7	10.91

Notes:

1. Past actual emissions of SO_2 and NO_x based on Acid Rain CEMS (Maximum annual average from a 24 month period in past 5 years).
2. Past actual emissions of PM_{10}, VOC, and CO based on coal usage (heat input 41,804,351 MMBtu/yr) (Maximum annual average from a 24 month period in past 5 years) and AP42 (9/98) Chapter 1.1 emission factors. Average heat content of coal burned was 8,771 Btu/lb.
3. Sulfuric Acid emissions based on SO_2 emissions and factors developed by Southern Company. E1' (emission rate, lb/yr) = K (MW and units constant) * F1 (fuel impact factor) * F2 (technology impact factor) * E2 (SO2 emissions, tpy).
4. Projected future actual does not include increases from system generation demand growth.

Significantly, any increases of facility operations or emissions that are attributable to increased customer demand are not considered as increases for PSD evaluation. This exemption is clearly supported in the WEPCO and Detroit Edison decisions.

Therefore, in calculating future actual emissions for compliance demonstration purposes emission changes associated with increased utilization (but not associated with the proposed project, e.g. generation demand) are not included. The WEPCO rule expressly excludes from relevance any increase in emissions that are attributable to increased capacity utilization due to future system demand growth or the utility system. In addition, the future actual test period will be limited to five years.

PROPOSAL

OG&E proposes to limit emissions (excluding increases due to system generation demand (40 CFR § 52.21(b)(33)(ii)) on Unit 1 after economizer replacement, turbine project and boiler surface project such that the emission increase will not exceed the PSD significant threshold increase level. OG&E will maintain and submit to ODEQ on a calendar year basis for a period of five years starting with the first full calendar year after the date the unit resumes regular operation, information demonstrating that the economizer replacement and turbine project did not result in an emissions increase.

APPENDIX A

U.S. EPA REGION V LETTER

May 23, 2000

R-19J

Henry Nickel
Counsel for the Detroit Edison Company
Hunton & Williams
1900 K Street, N.W.
Washington D.C. 20006-1109

Dear Mr. Nickel:

I am responding to your request on behalf of the Detroit Edison Company for an applicability determination regarding the proposed replacement and reconfiguration of the high pressure section of two steam turbines at the company's Monroe Power Plant, referred to as the Dense Pack project. Specifically, you requested that the United States Environmental Protection Agency (EPA) determine whether the Dense Pack project at the Monroe Power Plant would be considered a major modification that would subject the project to pollution control requirements under the Prevention of Significant Deterioration (PSD) program.

We have reviewed your original request, dated June 8, 1999, and the supplemental information you submitted on December 10, 1999, and March 16, 2000. We provisionally conclude that the Dense Pack project would not be a major modification. Thus, Detroit Edison may proceed with the project without first obtaining a PSD permit. Although the Dense Pack project would constitute a nonroutine physical change to the facility that might well result in a significant increase in air pollution, Detroit Edison asserts that emissions will not in fact increase due to the construction activity, and EPA has no information to dispute that assertion.

As you know, nonroutine changes of any type, purpose, or magnitude at an electric utility steam generating unit -- ranging from projects to increase production efficiency to even the complete replacement of entire major components -- are excluded from PSD coverage as long as they do not significantly increase emissions from the source. Thus, Detroit Edison has been free to proceed at any time with the Dense Pack project without first obtaining a PSD permit as long as it adheres to its stated intention to not increase emissions as a result of the project. Indeed, EPA encourages the company to proceed with the project on this basis, since it appears to both reduce emissions per unit of output and not increase actual air pollution.

As you are also aware, under the applicable new source review regulations, in determining if a physical change will result in a significant emissions increase at an electric utility plant, companies may use an "actual" to "representative actual annual emissions" test for emissions from the electric utility steam generating unit, under which a calculation of baseline emissions and a projection of future emissions after the change is needed. Our determination of nonapplicability is provisional because Detroit Edison has not, to our knowledge, provided a calculation of baseline emissions or projected future emissions to the permitting agency, and this should be done prior to the start of construction. The basis for this determination is summarized below and is set forth in full in the enclosed detailed analysis.

In determining whether an activity triggers PSD, the Clean Air Act and EPA's regulations

specify a two-step test. The first step is to determine if such activity is a physical or operational change, and if it is, the second step is to determine whether emissions will increase because of the change. The statute admits of no exception from its sweeping scope, but EPA's regulations contain some narrow exceptions to the definition of physical or operational change. In particular, Detroit Edison claims that the Dense Pack project is eligible for the exclusion for routine maintenance, repair, and replacement. The determination of whether a proposed physical change is "routine" is a case-specific determination which takes into consideration the nature, extent, purpose, frequency, and cost of the work, as well as other relevant factors. After carefully reviewing all the information you submitted in light of the relevant factors, EPA has determined that the proposed project is not "routine."

The purpose of the Dense Pack project, to significantly enhance the present efficiency of the high pressure section of the steam turbine, signifies that the project is not routine. An upgrade of this nature is markedly different from the frequent, inexpensive, necessary, and incremental maintenance and replacement of deteriorated blades that is commonly practiced in the utility industry. For instance, past blade maintenance and replacement of only the deteriorated blades at Detroit Edison has never increased efficiency over the original design. Accordingly, because increasing turbine efficiency by a total redesign of a major component is a defining feature of the proposed Dense Pack project, it clearly goes significantly beyond both historic turbine work at Detroit Edison, and what would otherwise be considered a regular, customary, or standard undertaking for the purpose of maintaining the existing steam turbine units. The project also goes well beyond routine turbine maintenance, repair, and replacement activities for the utility industry in general.

The nature and extent of the work in question -- replacement of the entire high pressure sections of the steam turbines for Units 1 and 4 at Monroe -- suggests that the Dense Pack project is not routine. It would result in greater efficiency above the level that can be reached by simply replacing deteriorated blades with ones of the same design and, in addition, will substantially increase efficiency over the original design. Specifically, the Dense Pack upgrade would not only restore the 7 percent of the efficiency rating lost over the years at each unit but would improve the unit's efficiency by an additional 5 percent over its original design capacity. Accordingly, the proposed project represents a significant and major redesign and replacement of the entire high pressure sections of the steam turbines at Units 1 and 4 at the Monroe facility.

The frequency with which utilities have undertaken turbine upgrades like the Dense Pack project also indicates the nonroutine nature of the changes. The information provided by Detroit Edison, regarding past history at the Monroe facility, describes what is characterized as necessary maintenance, repair, and replacement of deteriorated turbine blades approximately every 4 years. During these overhaul periods, it is not uncommon for the company to replace up to several turbine blades at one time. It is common among other utilities to also perform similar turbine maintenance. However, Detroit Edison has not provided any information to suggest that a complete replacement and redesign of the high pressure section of a steam turbine is conducted frequently at Monroe or at any other individual utility. Instead, Detroit Edison relies on its claim that projects "similar" to the Dense Pack project have been performed at a number of utilities. This information does not indicate that the replacement of the high pressure section of the steam turbine is frequent at the typical utility source; to the contrary, the only available information

reflects that projects like the Dense Pack project have been performed only one time, if ever, at individual sources.

The cost of the Dense Pack project is significant and tends to indicate that this project is nonroutine. Detroit Edison expects the Dense Pack replacement to cost approximately $6 million for each turbine unit, for a total of $12 million. The EPA has rejected claims of routineness in past cases where the cost was substantially less than this figure. Moreover, Detroit Edison intends to capitalize the entire cost of this project, and EPA believes that a $12 million project that is 100 percent capital improvement indicates that it is a major undertaking.

Beyond the clearly significant absolute cost of this project, available information suggests that this expenditure far exceeds the cost typically associated with turbine blade maintenance activity. Detroit Edison provided only a summary of the total project costs for past maintenance and inspections at the facility, the total costs of which ranged from less than $1 million to a little more than $6 million. Although Detroit Edison did not provide any detail regarding what specific activities comprise these aggregated amounts, it acknowledges that it spent only $18,700, $33,100, and $7,900 to replace high-pressure rotors in three turbine projects in 1981 and 1982. Further, the project is significantly more costly than simply replacing deteriorated blades today; Detroit Edison acknowledges that the Dense Pack upgrade would cost three times more than its alternative blade repair and replacement project. Accordingly, it appears that the costs associated with the Dense Pack project greatly exceed the amounts spent previously by Detroit Edison or that it would spend presently for the replacement of deteriorated turbine blades or rotors.

For the reasons delineated above, we conclude that the changes proposed by Detroit Edison are not routine. Detroit Edison's submissions do not demonstrate that projects such as the Dense Pack project are frequent, inexpensive, or done for the purpose of maintaining the facility in its present condition. Instead, the source relies on two principal arguments: (1) it claims that this project is less significant in scope than was the activity in question in the 1988 applicability determination for the Wisconsin Electric Power Company (WEPCO); and (2) it alleges that EPA has interpreted the exclusion for routine activity expansively to exempt all projects that do not increase a unit's emission rate. EPA rejects both of these arguments, the former because both EPA and the U.S. Court of Appeals for the Seventh Circuit viewed WEPCO's activity as "far from" routine and thus this attempted comparison to WEPCO is unsuitable, and the latter because it is demonstrably incorrect. The attached analysis addresses these points in significant detail.

When nonroutine physical or operational changes significantly increase emissions to the atmosphere, they are properly characterized as major modifications and are subject to the PSD program. In general, a physical change in the nature of the Dense Pack project, which provides for the more economical production of electricity, would be expected to result in the increased utilization of the affected units, and thus, increased emissions. Notwithstanding the fact the Monroe units may be high on the dispatch order, the Dense Pack project would allow Detroit Edison to produce electricity more cheaply per unit of output, thereby creating an incentive to run Units 1 and 4 above current levels. Even a small increase over current normal levels in the utilization of the affected units would result in a significant increase in actual emissions of criteria pollutants. For example, in 1997, at the Monroe facility Unit 1 emitted approximately

14,000 tons of nitrogen oxides (NOx) and 41,000 tons of sulfur dioxide (SO2), and Unit 2 emitted 12,000 tons of NOx and 35,000 tons of SO2. Based on this information, if a one to five percent increase in operation were to result from the Dense Pack project, increases on the order of 160-800 tons of NOx and 400-2000 tons of SO2 would occur.

Detroit Edison, however, maintains that emissions will not increase as a result of the Dense Pack project. Specifically, the company contends that representative actual annual emissions following the change will not be greater than its pre-change actual emissions, because the Dense Pack upgrade will not result in increased utilization of the units. As you are aware, the PSD regulations (under the provisions commonly known as the "WEPCO rule") allow a source undertaking a nonroutine change that could affect emissions at an electric utility steam generating unit to lawfully avoid the major source permitting process by using the unit's representative actual annual emissions to calculate emissions following the change if the source submits information for 5 years following the change to confirm its pre-change projection. In projecting post-change emissions, Detroit Edison does not have to include that portion of the unit's emissions which could have been accommodated before the change and is unrelated to the change, such as demand growth.

Under the WEPCO rule, Detroit Edison must compute baseline actual emissions and must project the future actual emissions from the modified unit for the 2-year period after the physical change (or another 2-year period that is more representative of normal operation in the unit's modified state). As noted above, Detroit Edison has not provided these figures to verify its projection of no increase in actual emissions, and should submit them to the Michigan Department of Environmental Quality prior to beginning construction. In addition, Detroit Edison must maintain and submit to the permitting agency on an annual basis for a period of at least 5 years (or a longer period not to exceed 10 years, if such a period is more representative of the modified unit's normal post-change operations) from the date the units at the Monroe Plant resume regular operation, information demonstrating that the renovation did not result in a significant emissions increase. If Detroit Edison fails to comply with the reporting requirements of the WEPCO rule or if the submitted information indicates that emissions have increased as a consequence of the change, it will be required to obtain a PSD permit for the Dense Pack project.

Finally, regardless of whether PSD review is triggered due to the Dense Pack project, Detroit Edison must meet all other applicable federal, state, and local air pollution requirements.

This determination will be final in 30 days unless, during that time, Detroit Edison seeks to confer with or appeal to the Administrator or her designee regarding it. If you have any questions regarding this determination, please contact Laura Hartman, Environmental Engineer, at (312) 353-5703, or Jane Woolums, Associate Regional Counsel, at (312) 886-6720.

Sincerely,

/s/

Francis X. Lyons
Regional Administrator

Enclosure

cc: Peter Marquardt, Esq., Special Counsel
Detroit Edison Company
2000 Second Avenue - 688 WCB
Detroit, Michigan 48336

Russell Harding, Director
Michigan Department of Environmental Quality

APPENDIX B

ACID RAIN CEMS DATA AND ANNUAL AVERAGES

Year-Month	HI (mmBtu)	SO2 (tons)	NOx (tons)	Avg SO_2[1] (tons)	Avg NO_x[1] (tons)	Avg HI[1] (mmBtu)	Avg VOC[1]	Avg CO[1]	Avg PM10[1]	Avg H_2SO_4[1]
2001-01	3057745	712.4898	497.2016							
2001-02	2543332	759.871	492.6993							
2001-03	3355178	866.3827	521.6921							
2001-04	2434064	642.0107	412.411							
2001-05	3094810	783.1545	519.1381							
2001-06	3119344	811.8341	473.071							
2001-07	3371744	907.9723	544.61							
2001-08	3431702	1004.219	566.4108							
2001-09	2938867	846.6383	471.2375							
2001-10	482346.7	120.9193	72.38099							
2001-11	1734729	491.7892	354.0892							
2001-12	3585089	1031.385	679.842							
2002-01	3440326	970.6282	528.1031							
2002-02	2304345	583.479	395.8051							
2002-03	3656539	968.0357	614.7252							
2002-04	3694200	963.1108	674.5611							
2002-05	3685421	903.38	687.7911							
2002-06	3568254	805.6952	585.1012							
2002-07	3700724	964.1178	667.9234							
2002-08	3809730	924.657	696.0999							
2002-09	3534471	898.1628	606.6813							
2002-10	3528624	805.8311	659.1569							
2002-11	3663522	934.2122	745.2954							
2002-12	3601150	923.0372	530.3873	9811.506	6498.207	37668129	64.41933	536.8277	403.8023	3.759586
2003-01	4010129	1029.54	765.8959	9970.031	6632.554	38144321	65.2337	543.6142	408.9071	3.82033
2003-02	3386279	850.7037	629.9101	10015.45	6701.16	38565794	65.9545	549.6208	413.4253	3.837732
2003-03	3666482	796.5588	656.8356	9980.536	6768.732	38721447	66.22069	551.8391	415.0939	3.824355
2003-04	825638.6	195.1917	153.7343	9757.126	6639.393	37917234	64.84534	540.3779	406.4727	3.738748
2003-05	3417309	783.1042	565.7941	9757.101	6662.721	38078483	65.12111	542.6759	408.2013	3.738739
2003-06	3446947	812.339	631.2324	9757.354	6741.802	38242285	65.40124	545.0103	409.9573	3.738835
2003-07	3687851	977.1302	555.9967	9791.933	6747.495	38400338	65.67154	547.2628	411.6516	3.752085
2003-08	3714229	883.7931	578.708	9731.72	6753.644	38541602	65.91313	549.2761	413.166	3.729013
2003-09	3435756	942.6162	588.8917	9779.709	6812.471	38790046	66.33801	552.8168	415.8293	3.747402
2003-10	3818620	997.2095	585.4352	10217.85	7068.998	40458183	69.19083	576.5902	433.7117	3.915291

[1] Annual Average in tons from previous 24 months

Year-Month	HI (mmBtu)	SO2 (tons)	NOx (tons)	Avg SO_2[1] (tons)	Avg NO_x[1] (tons)	Avg HI[1] (mmBtu)	Avg VOC[1]	Avg CO[1]	Avg PM10[1]	Avg H_2SO_4[1]
2003-11	3574589	952.4665	602.0398	10448.19	7192.973	41378113	70.76407	589.7006	443.5734	4.003552
2003-12	3323714	805.4379	546.5033	10335.22	7126.304	41247426	70.54058	587.8381	442.1724	3.960263
2004-01	3515033	802.7101	621.8045	10251.26	7173.155	41284779	70.60446	588.3705	442.5728	3.928091
2004-02	3196822	805.33	545.8	10362.19	7248.152	41731018	71.3676	594.73	447.3565	3.970596
2004-03	3803206	1102.45	845.29	10429.39	7363.435	41804351	71.49302	595.7752	448.1423	3.996348
2004-04	3225359	918.95	711.74	10407.31	7382.024	41569931	71.09212	592.4343	445.6297	3.987887
2004-05	3141525	814.31	573.89	10362.78	7325.073	41297983	70.62704	588.5586	442.7144	3.970822
2004-06	3200585	877.75	635.82	10398.8	7350.433	41114148	70.31265	585.9387	440.7437	3.984627
2004-07	3536283	1006.82	739.48	10420.16	7386.211	41031927	70.17203	584.767	439.8623	3.992809
2004-08	3467269	990.34	703.87	10453	7390.096	40860697	69.8792	582.3267	438.0267	4.005393
2004-09	2005839	468.5629	346.5959	10238.2	7260.054	40096381	68.57208	571.434	429.8332	3.923086
2004-10	2111144	570.799	399.2665	10120.68	7130.108	39387641	67.36001	561.3334	422.2355	3.878056
2004-11	3520227	901.2702	715.6559	10104.21	7115.289	39315993	67.23748	560.3123	421.4675	3.871744
2004-12	3588968	889.3613	762.2754	10087.37	7231.233	39309903	67.22706	560.2255	421.4022	3.865292
2005-01	3619618	908.223	749.0958	10026.71	7222.833	39114647	66.89314	557.4428	419.309	3.842049
2005-02	3600556	860.0578	786.8529	10031.39	7301.304	39221786	67.07636	558.9697	420.4575	3.843841
2005-03	3595420	827.9668	777.3809	10047.09	7361.577	39186254	67.0156	558.4633	420.0766	3.849859
2005-04	3790761	884.4231	820.8127	10391.71	7695.116	40668816	69.55105	579.5921	435.9697	3.981909
2005-05	3443655	795.9136	695.7959	10398.12	7760.117	40681989	69.57358	579.7798	436.1109	3.984363
2005-06	3344089	895.5022	686.1464	10439.7	7787.574	40630560	69.48562	579.0469	435.5596	4.000297
2005-07	3551240	932.8789	699.3237	10417.57	7859.237	40562254	69.36881	578.0734	434.8274	3.991818
2005-08	3619489	857.5678	627.5254	10404.46	7883.646	40514884	69.2878	577.3983	434.3196	3.986794
2005-09	3452545	859.6855	667.4746	10362.99	7922.937	40523278	69.30215	577.5179	434.4095	3.970905
2005-10	3429243	818.5056	752.3227	10273.64	8006.381	40328589	68.9692	574.7433	432.3225	3.936667
2005-11	3130068	777.5203	637.0639	10186.17	8023.893	40106329	68.58909	571.5758	429.9398	3.903149
2005-12	2797144	741.4937	531.8341	10154.2	8016.559	39843043	68.13883	567.8236	427.1174	3.890898
Maximum Annual Average				10453.00	8023.89	41804350.99	71.49	595.78	448.14	4.01

[1] Annual Average in tons from previous 24 months